CALIFORNIA ENERGY COMMISSION

SUMMER 2009 ELECTRICITY SUPPLY AND DEMAND OUTLOOK

STAFF REPORT

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Arnold Schwarzenegger, *Governor*

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Abstract

The Summer 2009 Electricity Supply and Demand Outlook provides a summary of the California Energy Commission staff assessment of electricity system or grid capability to provide power to meet electricity demand within California. The report also documents key assumptions and methodologies used to develop an assessment of physical resources.

Keywords: Supply and demand outlook, probability, operating reserve, loss of load, demand, forced outage, generation, net interchange, demand response, interruptible load, reserve margin

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Summary

The Summer 2009 Electricity Supply and Demand Outlook (*2009 Outlook*) provides a summary of the California Energy Commission (Energy Commission) staff assessment of the physical electricity system's capability to meet peak electricity demand in California. This assessment includes three smaller geographic regions: the California Independent System Operator (California ISO) Control Area, and the California ISO's northern and southern sub-regions.[1]

California is expected to have adequate electricity supplies to meet peak demand this summer even if hotter-than-average temperatures occur. Although the snow pack and forecast runoff are once again below average, adequate hydroelectric generation capacity is expected to be available to meet peak power needs.

The likelihood of having adequate supplies is increased with a 15 to 17 percent "buffer" of additional supplies above expected peak demand that are available as needed. This "buffer" is referred to as a "planning reserve margin."[2] **Table 1** shows that statewide electricity reserve margins for 2009 range from 23 to 35 percent over the summer months, which exceeds the planning reserve margin target. With these reserve margins there should be sufficient resources to cover most system contingencies, including high demand due to hot weather conditions. The reserve margins under unusually hot summer weather conditions range from 16 to 22 percent.[3] For comparison, the estimated planning reserve margins in the *Summer 2008 Electricity Supply and Demand Outlook Report* were lower, averaging about 22 percent for average weather conditions and 14 percent for hot conditions.[4]

There are a number of differences between the *2008* and *2009 Outlook Reports*. Additional generation capacity is expected to be operational this summer compared to last year (1,419 MW compared to 671 MW). The projected growth in peak demand for electricity is also lower under both average and hot summer weather conditions, reflecting the current economic downturn. There is also a slight increase in the combined voluntary demand response and interruptible program values that contribute to the planning reserve margin difference from 2008.

[1] The report does not include either an evaluation of the condition of the electricity market, specific contractual details, or the adequacy of any individual utility or local distribution systems.

[2] A planning reserve margin defines the minimum level of electricity supplies needed to cover a range of unexpected contingencies, such as increased air conditioning demand on a hotter than-average day or an unplanned maintenance at a power plant. Planning reserve margin targets are based on average system conditions. A description of the planning reserve margin calculations is provided in **Appendix B**.

[3] Existing generation includes capacity either actually added or retired, or expected to be added or retired, between August 1, 2008 and May 31, 2009.

[4] *Summer 2008 Electricity Supply and Demand Outlook* (*2008 Outlook*, Table 1: California 2008 Summer Outlook (MW), p. 1.

The most significant change in the *2009 Outlook* from prior reports is the methodology used to determine exports from the northern portion to southern portion of the California ISO control area. Additional study of actual power flows indicate a trend of less power flowing north to south during periods of higher temperatures in Southern California.

Table 1: Statewide 2009 Summer Outlook (MW)

	Resource Adequacy Planning Conventions	June	July	August	September
1	Existing Generation (Note 1)	59,930	59,930	59,930	60,329
2	Expected Retirements (Note 1)	0	0	0	0
3	Expected Additions (Notes 1 & 2)	0	0	399	0
4	Net Imports (Note 3)	13,118	13,118	13,118	13,118
5	Total Net Generation (MW)	73,048	73,048	73,447	73,447
6a	Expected 1-in-2 Normal Summer Temperature Demand	55,861	60,924	61,623	57,898
6b	Expected 1-in-10 Unusually Hot Summer Temperature Demand	62,116	65,150	65,811	64,330
7a	Demand Response (DR)	635	648	653	655
7b	Interruptible/Curtailable Programs	1,935	1,938	1,946	1,942
9a	**Planning Reserve Margin (1-in-2 Demand)**	**35%**	**24%**	**23%**	**31%**
9b	**Planning Reserve Margin (1-in-10 Demand)**	**22%**	**16%**	**16%**	**18%**

Source: Energy Commission Staff

Notes: 1) Existing generation includes capacity either actually added or retired, or expected to be added or retired, between August 1, 2008 and May 31, 2009.

2) The addition shown is EIF Panoche. See footnote in Table 6, 2009 Additions and Retirements regarding timing.

3) Net import equals imports into California minus exports. This is also referred to as net interchange.

Although no specific generation capacity retirements are expected before August 1, 2009, **Appendix A** includes a discussion of the potential impacts of retiring up to 500 MW of aging generation in the Los Angeles Basin area.[5] The appendix also introduces the issues associated with the South Coast Air Quality Management District's (SCAQMD) *Priority Reserve Rule*, which may affect retirement decisions and constrain the development of new generation capacity that will be needed for reliability and system stability concerns.

A second measure of system adequacy is expressed as an operating reserve margin.[6] Dropping below a specified operating reserve margin target will require additional purchases of power, and calls for demand response and voluntary interruptible programs to avoid the possibility of uncontrolled outages that can cascade throughout the west. The California ISO calls warning stages at 7 percent (Stage 1) and 5 percent (Stage 2). Stage 3 is called when reserves fall to a level between 3 and 1.5 percent, depending on the specific operating conditions.

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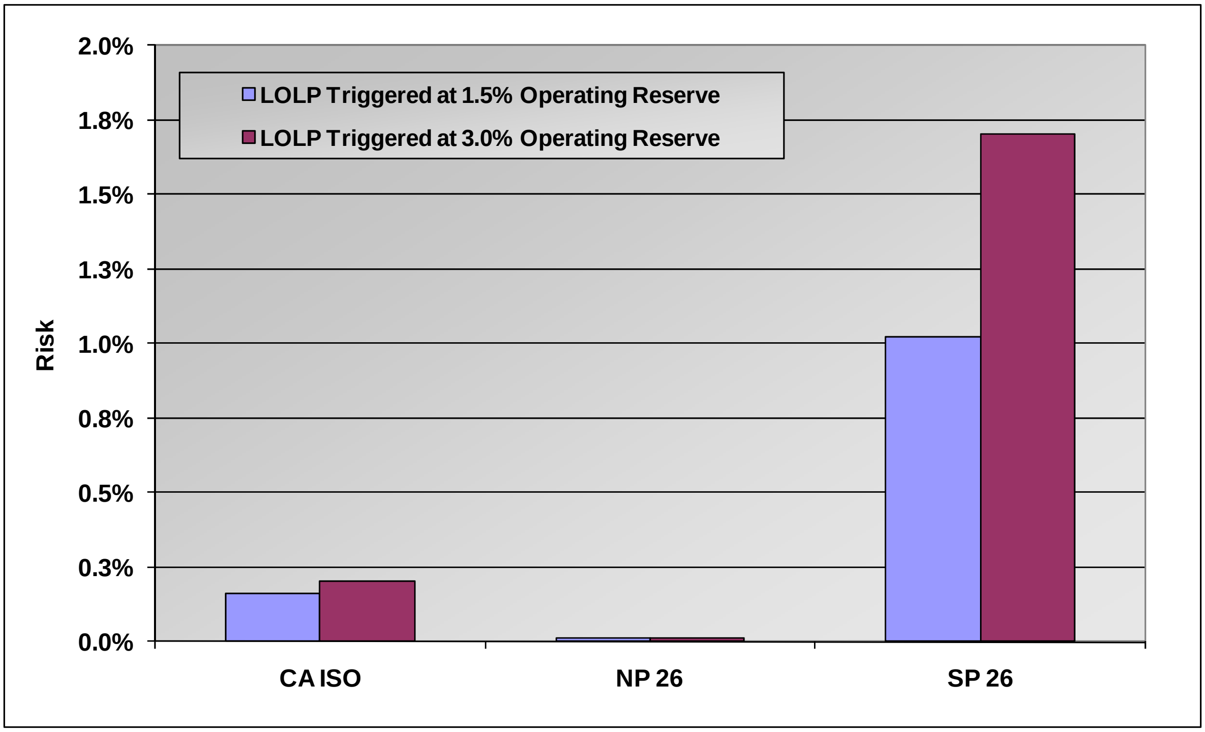
[5] The California Public Utilities Commission adopted phased retirements of aging plants starting in 2009, but it did not specify either the plant or plants expected to retire, or whether the retirement(s) would occur prior to or after the summer period. (D.07-12-052, December 12, 2007) At this time, it is uncertain if any retirements may actually take place under this decision.

[6] Operating reserve margin is the amount of imports and actual spinning generation above current demand and represents real-time operations that fluctuate minute by minute.

The southern portion of the California ISO (SP 26), covering most of Southern California, has a 1.7 percent probability of experiencing a Stage 3 emergency this summer. The California ISO Control Area and its northern sub-region (NP 26) each have a probability of rotating outages of less than half of 1 percent (0.5 percent) (**Figure 1)**.

Figure 1: Loss of Load Probability



Source: Energy Commission Staff

A probability cannot be expressed for a California total because the statewide system is composed of multiple control areas and does not operate as a single system. While this assessment covers electricity generation and the large interconnected transmission system, it does not include possible failures within local distribution systems.

2009 Summer Supply and Demand Outlook

This outlook examines four regions - Statewide, the California ISO Control Area overall, and California ISO's system north of Path 26 (NP 26) and south of Path 26 (SP 26):

- The Statewide region includes the major investor-owned and municipal utilities in the state.
- The California ISO Control Area is divided into Northern and Southern California sub-regions because there are transmission constraints south of the transmission segment

known as Path 26, which limit the transfer of electricity from north to south. The two sub-regions are referred to as NP 26 ("North of Path 26") and SP 26 ("South of Path 26"). The combination of the two sub-regions is referred herein as the California ISO region.

- The NP 26 region includes the Pacific Gas and Electric (PG&E) service area, and the participating municipal utilities and Energy Service Providers (ESPs) in Northern California served by the California ISO.
- The SP 26 region includes Southern California Edison (SCE), San Diego Gas and Electric (SDG&E), Southern California municipal utilities and ESPs that participate in the California ISO system.

The *2009 Outlook* summarizes a deterministic assessment (a single point forecast) of expected peak demand, electricity imports and in-state generation reserves under average and hotter than normal summer conditions.[7] The *2009 Outlook* also includes a probabilistic assessment (ranges of possible outcomes) to evaluate the cumulative risks of generation and transmission outages under variant peak demand levels. This assessment evaluates the likelihood that California may experience low operating (real-time) reserve margins and involuntary outages. The statewide outlook is only presented in a deterministic format because the electricity system is composed of multiple control areas and does not operate as a single entity.

Regional Reserve Margins

Table 2 through **Table 5** provide the estimated reserve margins for each of the four regions using demand projections under two types of weather conditions, the average summer conditions referred to as the "1-in-2" conditions, and the hotter, more adverse weather conditions known as "1-in-10" conditions. For the entire summer of 2009, the reserve margins for all regions under 1-in-2 weather conditions are expected to be higher than the target 15 percent planning reserve margin, with the closest being 22 percent in SP 26 during August. These reserve margins imply that there should be sufficient resources to cover a range of other system contingencies, such as unplanned facility outages or higher than expected demand due to hot weather conditions.

Under 1-in-10 weather conditions, the lowest reserve margin is expected to be 13 percent for SP 26 in August. This is the only instance that the calculated reserve margin drops below 15

[7] The *2009 Outlook* is based on forecasted loads in each region and the regional forecast of demand documented in *Revised 2010 Peak Demand Forecast*, (Energy Commission 2009 CEC-200-2009-001-CMD). The revised peak demand forecast for the SCE area is 700 MW lower than in the previous demand forecast, *California Energy Demand 2008 – 2018 Staff Revised Forecast*, published in November 2007.

percent. Regardless, the relevant 15 percent planning reserve margin target is based on average 1-in-2 conditions and anything above 15 percent is intended to cover a range of system contingencies, including a 1-in-10 hot and adverse summer.

Table 2: Statewide 2009 Summer Outlook (MW)

	Resource Adequacy Planning Conventions	June	July	August	September
1	Existing Generation (Note 1)	59,930	59,930	59,930	60,329
2	Expected Retirements (Note 1)	0	0	0	0
3	Expected Additions (Notes 1 & 2)	0	0	399	0
4	Net Imports (Note 3)	13,118	13,118	13,118	13,118
5	Total Net Generation (MW)	73,048	73,048	73,447	73,447
6a	Expected 1-in-2 Normal Summer Temperature Demand	55,861	60,924	61,623	57,898
6b	Expected 1-in-10 Unusually Hot Summer Temperature Demand	62,116	65,150	65,811	64,330
7a	Demand Response (DR)	635	648	653	655
7b	Interruptible/Curtailable Programs	1,935	1,938	1,946	1,942
9a	**Planning Reserve Margin (1-in-2 Demand)**	**35%**	**24%**	**23%**	**31%**
9b	**Planning Reserve Margin (1-in-10 Demand)**	**22%**	**16%**	**16%**	**18%**

Source: Energy Commission Staff

Notes: 1) Existing generation includes capacity either actually added or retired, or expected to be added or retired, between August 1, 2008 and May 31, 2009.
2) The addition shown is EIF Panoche.
3) Net import equals imports into California minus exports. This is also referred to as net interchange.

Table 3: California ISO 2009 Summer Outlook (MW)

	Resource Adequacy Planning Conventions	June	July	August	September
1	Existing Generation (Note 1)	48,379	48,379	48,379	48,778
2	Expected Retirements (Note 1)	0	0	0	0
3	Expected Additions (Notes 1 & 2)	0	0	399	0
4	Net Imports (Note 3)	10,350	10,350	10,350	10,350
5	Total Net Generation (MW)	58,729	58,729	59,128	59,128
6a	Expected 1-in-2 Normal Summer Temperature Demand	44,824	48,499	48,921	45,993
6b	Expected 1-in-10 Unusually Hot Summer Temperature Demand	50,068	51,588	52,541	51,337
7a	Demand Response (DR)	435	448	453	455
7b	Interruptible/Curtailable Programs	1,935	1,938	1,946	1,942
9a	**Reserve Margin (1-in-2 Demand)**	**36%**	**26%**	**26%**	**34%**
9b	**Reserve Margin (1-in-10 Demand)**	**22%**	**18%**	**17%**	**20%**

Source: Energy Commission Staff

Notes: 1) Existing generation includes capacity either actually added or retired, or expected to be added or retired, between August 1, 2008 and May 31, 2009.
2) The addition shown is EIF Panoche.
3) Net import equals imports into California minus exports. This is also referred to as net interchange.

Table 4: NP 26 California ISO 2009 Summer Outlook (MW)

	Resource Adequacy Planning Conventions	June	July	August	September
1	Existing Generation (Note 1)	25,452	25,452	25,452	25,851
2	Expected Retirements (Note 1)	0	0	0	0
3	Expected Additions (Notes 1 & 2)	0	0	399	0
4	Net Imports (Note 3)	1,750	1,750	1,750	1,750
5	Total Net Generation (MW)	27,202	27,202	27,601	27,601
6a	Expected 1-in-2 Normal Summer Temperature Demand	20,371	21,954	20,530	19,518
6b	Expected 1-in-10 Unusually Hot Summer Temperature Demand	22,222	22,760	21,868	21,328
7a	Demand Response (DR)	127	128	130	131
7b	Interruptible/Curtailable Programs	653	655	663	660
9a	**Reserve Margin (1-in-2 Demand)**	**37%**	**27%**	**38%**	**45%**
9b	**Reserve Margin (1-in-10 Demand)**	**26%**	**23%**	**30%**	**33%**

Source: Energy Commission Staff

Notes: 1) Existing generation includes capacity either actually added or retired, or expected to be added or retired, between August 1, 2008 and May 31, 2009.

2) The addition shown is EIF Panoche.

3) Net import equals imports into California minus exports. This is also referred to as net interchange.

Table 5: SP 26 California ISO 2009 Summer Outlook (MW)

	Resource Adequacy Planning Conventions	June	July	August	September
1	Existing Generation (Note 1)	22,927	22,927	22,927	22,927
2	Expected Retirements (Note 1)	0	0	0	0
3	Expected Additions	0	0	0	0
4	Net Imports (Note 2)	10,100	10,100	10,100	10,100
5	Total Net Generation (MW)	33,027	33,027	33,027	33,027
6a	Expected 1-in-2 Normal Summer Temperature Demand	24,453	26,545	28,391	26,475
6b	Expected 1-in-10 Unusually Hot Summer Temperature Demand	27,846	28,828	30,673	30,009
7a	Demand Response (DR)	308	319	324	324
7b	Interruptible/Curtailable Programs	1,283	1,283	1,283	1,283
9a	**Reserve Margin (1-in-2 Demand)**	**42%**	**30%**	**22%**	**31%**
9b	**Reserve Margin (1-in-10 Demand)**	**24%**	**20%**	**13%**	**15%**

Source: Energy Commission Staff

Notes: 1) Existing generation includes capacity either actually added or retired, or expected to be added or retired, between August 1, 2008 and May 31, 2009.

2) Net import equals imports into California minus exports. This is also referred to as net interchange.

Table 6 lists the dependable capacity of all additions and retirements included in the *2009 Outlook*. These are additions and retirements that occurred since August 31, 2008, or that are believed to have a high probability of taking place prior to August 1, 2009. The statewide aggregate totals 1,419 MW of capacity added statewide during that timeframe. See **Appendix A** for a detailed presentation of additions and retirements.

Table 6: 2009 Additions and Retirements

California ISO Control Area					
SP26			**NP26**		
SP 26 Additions			***NP 26 Additions***		
Name	**MW**	**Expected or On-Line**	**Name**	**MW**	**Expected or On-Line**
Inland Empire (U1 & STG)	370	Jan	Gateway	530	Feb
			Starwood-Midway	120	May
			EIF Panoche	399	Aug
SP 26 Retirements			***NP 26 Retirements***		
Name	**MW**	**Month**	**Name**	**MW**	**Month**
-	0	**-**	**-**	0	**-**
Aggregate SP 26	**370**		**Aggregate NP 26**	**1,049**	
Aggregate California ISO Control Area: 1,419 MW					
Non-California ISO Control Area					
LADWP & IID Control Areas			**SMUD & TID Control Areas**		
LADWP & IID Additions			***SMUD & TID Additions***		
Name	**MW**	**Expected or On-Line**	**Name**	**MW**	**Expected or On-Line**
-	0	**-**	**-**	0	**-**
LADWP & IID Retirements			***SMUD & TID Retirements***		
Name	**MW**	**Month**	**Name**	**MW**	**Month**
-	0	-	-	0	-
Aggregate LADWP & IID	**0**		**Aggregate SMUD & TID**	**0**	
Aggregate Non-California ISO Control Area: 0 MW					
Aggregate Statewide	**1,419 MW**				

Source: Energy Commission Staff

The net imports assumption represents a conservative estimate of potential electricity imports into each region, based on the western system capability to provide surplus generation during peak demand periods. This interconnected, inter-dependent wholesale power market provides reliability support and broad cost savings benefits. The Pacific Northwest and the Desert Southwest regions each have a diverse mix of surplus electricity resources and different load patterns, which create opportunities to sell electricity to California during the summer season.

A study of the temperature and path flow relationships during the summer periods for 2006, 2007, and 2008 reveals that the previous 3,000 MW estimate is significantly higher than the actual path flows during periods of peak temperature conditions in Northern California. The net imports (also referred to as net interchange) value for NP 26 shown in Table 4 is an increase of 1,500 MW over the 250 MW value shown in 2008. A summary of this re-evaluation of electricity flows over Path 26 appears in **Appendix A**.

Appendix A provides a more detailed explanation of the different assumptions that are applied to the deterministic reserve margin outlook.

Probability Assessments

Figure 2 displays the estimate of the probability of involuntary load curtailment within the California ISO Control Area and the two sub-regions at the peak hour for the summer 2009 period. To maintain the Western Electricity Coordinating Council (WECC) Minimum Operating Reserve Criteria, the California ISO continuously recalculates the operating reserve margin and will declare a Stage 3 Emergency when reserves fall to a level between 1.5 and 3 percent, depending on the current system operating conditions.[8] The California ISO can initiate rotating customer curtailments under a Stage 3 Emergency to ensure that the system remains stable and avoid the possibility of uncontrolled outages that can cascade throughout the west.

The Loss of Load Probability (LOLP) estimates for both the low and high range operating reserve margins (1.5 and 3 percent, respectively) have been included in **Figure** 1**.** The actual LOLP would likely fall within the range between the two points estimated. The SP 26 region has the highest probability of involuntary load curtailment or rotating outages. The corresponding LOLP estimates for the region are between 1.0 and 1.7 percent. The California ISO Control Area and NP 26 both have an expected LOLP of less than one half of one percent (0.5 percent) for summer 2009.

Utilities not under the California ISO Control Area have adequate resources to meet expected electricity demand this summer. These public utilities include Los Angeles Department of Water and Power (LADWP), Burbank Water and Power, Glendale Water and Power, and Imperial Irrigation District (IID) in Southern California and Sacramento Municipal Utility District (SMUD), Modesto Irrigation, Redding, Roseville Electric, and Turlock Irrigation District (TID) in Northern California.

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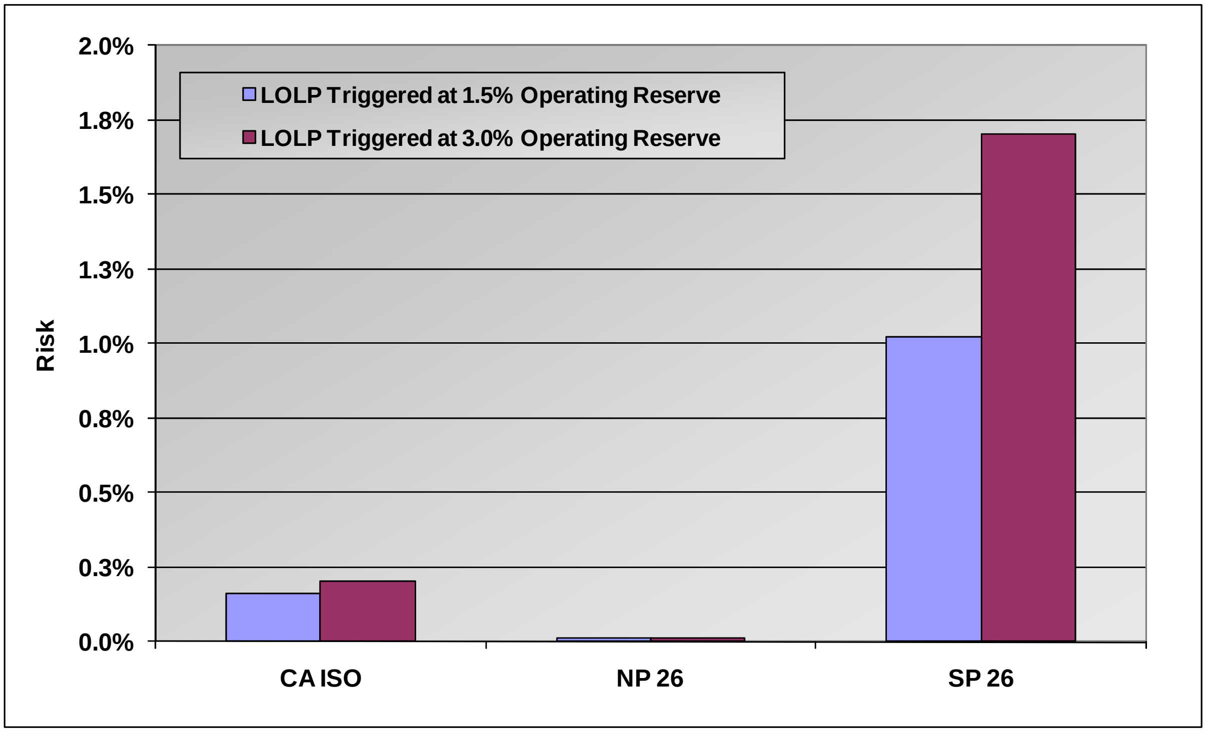
[8] The operating reserve margin does not include the generation that is not scheduled to operate, shut down for planned maintenance, unexpected failure outages, or unable to be delivered due to transmission problems. Actual demand levels may also be higher than expected when generation was scheduled to operate the day before and result in a shortfall in operating power plant supply.

Figure 2: Loss of Load Probability



Source: Energy Commission Staff

Regional Probabilistic Assessments

Planning reserve margins are a long-term measurement intended to assure sufficient electricity supplies can meet real-time operating reserve requirements and maintain a 1-in-10 year loss of load probability reliability target. The deterministic reserve margin calculations are suitable to evaluate whether each region within California falls within the planning reserve margin targets. This type of assessment, however, does not consider the probability of various system fluctuations occurring, nor the variability with which they occur. For example, it is possible that several generators could simultaneously fail and cause a decrease in operating reserves, but the deterministic assessment will not give an indication of the cumulative likelihood of this or other system emergency events. A statistical assessment of different system variables is necessary to evaluate the risks of realizing lower operating reserve levels. The probability assessment provides a more rigorous evaluation of the system risks compared to deterministic calculations of operating reserves.

The staff continues to employ a reasonably detailed probabilistic assessment of the electricity system to enhance the deterministic tables provided in previous reports. The deterministic tables presented in previous outlooks included estimated reserve margins for two operating scenarios: peak demand during average weather conditions (1-in-2) and hotter than expected (1-in-10) conditions. In system planning, however, neither supply nor demand can be predicted with absolute accuracy or determined by a single point forecast. Future conditions that determine load, as well as availability of supply, can be better characterized as falling within a range of uncertainty. Studies based only upon the most likely set of conditions fall short of looking at the full range of possible demand levels and the fluctuation in supply capabilities. Likewise, studies based on adverse conditions are still limited in scope and may overestimate the exposed risk to these events.

As the high loads experienced during the extended heat wave of the summer of 2006 illustrated, actual peak demand can be significantly higher than projected in the hotter than normal (1-in-10) forecast and the consequences will therefore not be captured by a deterministic methodology. This experience demonstrated the limitation of single- or two-point deterministic evaluations. Evaluating a wider range of factors and future conditions affecting supply adequacy to cover unexpected contingencies provides greater insight into the possible risks to supply adequacy.

The observed performance of the electricity system over time and an extensive record of temperature conditions that are correlated to actual demand have allowed the Energy Commission staff to develop probability of occurrence measures for several of the major uncertainty factors. Incorporating the probability of occurrence to an electricity supply assessment provides a better representation of the fluctuations in the system and measures the risks of actually encountering an electric system emergency event based on historical data.

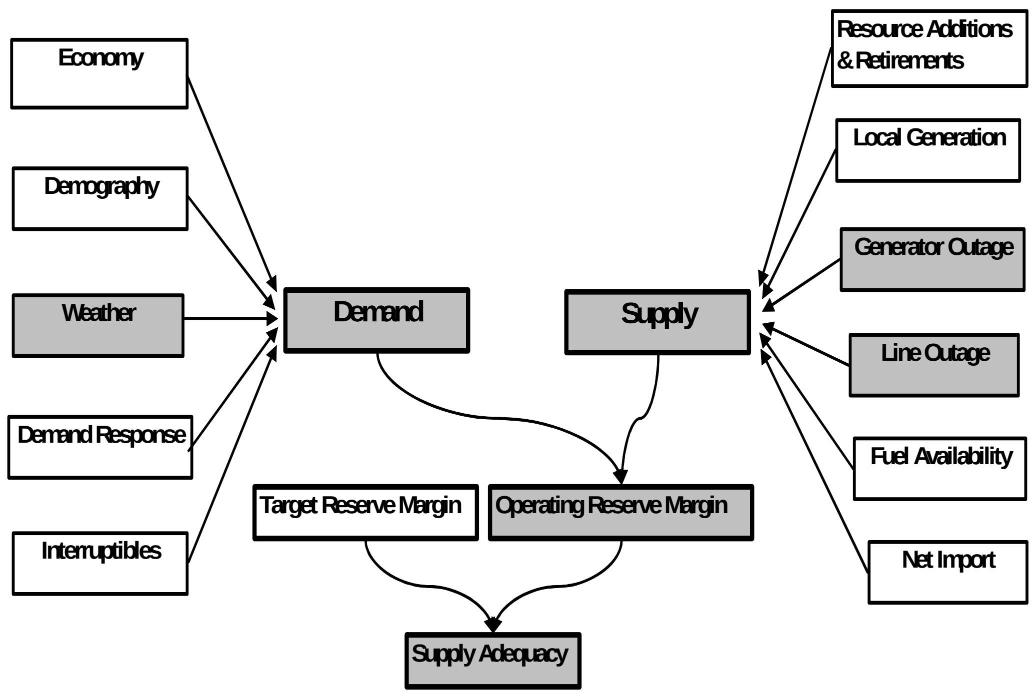
The Supply Adequacy Model (SAM) is a forecasting tool that assesses the balance of power supply and demand for a power system throughout the WECC regions. SAM was originally developed at the Energy Commission in 1998. For this analysis, the staff employed a modified version of the SAM to analyze a specific region. This modified version of the SAM is referred to as SAM-A. The SAM-A was designed to be a relatively fast and simple analytical tool with the capability of incorporating uncertainty variables. The probabilistic approach for analyzing supply adequacy is an important feature of SAM-A, which differs from deterministic models.

In the initial probabilistic study, the staff included the probabilities of high demand and generation forced outages in the Southern California (SP 26) portion of the California ISO Control Area. The SP 26 region was selected because it had the lowest planning reserve margin and presented the highest probability of not meeting operating reserve requirements. The *Summer 2006 Electricity Supply and Demand Outlook* incorporated the probability of forced outages of transmission lines in the SP 26 region. In the 2007 report, the staff added analysis of the entire California ISO Control Area and the NP 26 sub-region using the same three probabilistic variables of demand, generation outages and transmission outages. The approach of analyzing the entire control area, along with the sub-regions was continued in the 2008 report and remains the preferred approach in the 2009 outlook.

There are a number of variables to consider when assessing supply adequacy of a system. This probabilistic assessment evaluates the complete range of demand scenarios based on weather variation, as well as generation and transmission outage occurrences based on historical data. The staff developed multiple cases of different resource availability, transmission capabilities and demand-varying scenarios using the Monte Carlo method to determine physical supply adequacy.

Figure 3 shows the major factors used to develop the 2009 outlook. The probabilistic methodology was applied to the factors in the highlighted boxes in the chart.

Figure 3: Major Factors Affecting Supply Adequacy



Source: Energy Commission Staff

Staff continues to explore the expansion of the probabilistic methodology and seeks to incorporate the effects of additional factors via random variables as more information becomes available from stakeholders, system operators as well as other public and private data collection efforts. The following description is an explanation of how the probabilistic methodology was applied to analyze the SP 26 region. The analytical process is the same for all three regions, but SP 26 was selected for illustrative purpose because it has the highest risk of firm load curtailments.

Probability of Demand

The probability of demand calculations are based on the load-temperature response estimated from the summer of 2006 daily peak demands, applied to the most recent adopted Energy Commission peak demand forecast.[9]

Peak electricity demand does not always occur in the hottest day of the year. There is a strong correlation between peak electricity demand and a build-up of high temperatures over several days. The staff method for assessing demand-temperature response is documented in previous reports.[10] Staff used Federal Energy Regulatory Commission (FERC) Form 714 hourly load data and utility planning area daily temperatures to estimate the relationship between summer weekday afternoon peaks and temperatures. The estimation included days from June 15 through September 15 on which the weighted average maximum temperature was above 75 degrees in Southern California Edison (SCE) or Pacific Gas and Electric (PG&E), or 70 degrees in San Diego Gas and Electric (SDG&E) service territories.

The temperature variables for each utility are weighted average temperatures from weather stations representative of the climate in that particular utility's region. Because residential air conditioning is the primary driver of day-to-day changes in peak demand, weather station weights are based on the estimated number of residential air conditioning units in each of the utility forecast zones in the Energy Commission's residential demand forecast model.

Two separate weather variables are calculated for this analysis. The first is a weighted average of maximum temperatures for three days. This weighting consists of 60 percent of the current day's maximum temperature, 30 percent of the previous day's maximum temperature, and 10 percent of the second previous day's maximum temperature. This lag is used to account for heat build-up over a three-day period. The daily temperature spread, or diurnal variation, is the second temperature variable. This variable is the daily maximum temperature less the daily minimum temperature. It serves as a proxy measure of daily humidity and also captures the effect of lack of nighttime cooling on peak demand.

Figure 4 and **Figure 5** illustrate the relationship between 2006 temperatures and loads, plus the estimated weather response function for SCE and SDG&E respectively. The daily afternoon peak demand is regressed against the weighted daily maximum temperature, the daily temperature spread, and a variable identifying weekends and holidays. A one degree increase in weighted average temperature equates to a 404 MW increase in peak demand for SCE and a 85 MW increase for SDG&E.

To derive the demand under various temperatures, the estimated coefficients are applied to the historic daily temperatures to calculate predicted annual maximum peak demands. The

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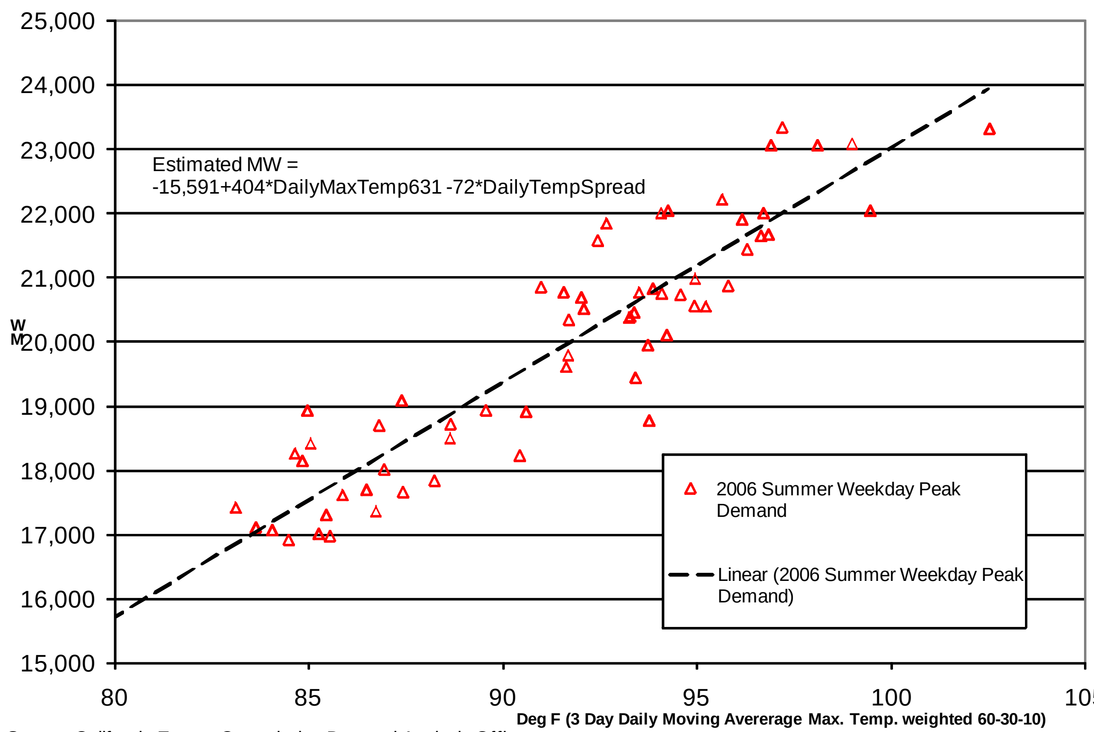
[9] *Revised 2010 Peak Demand Forecast*, (Energy Commission 2009 CEC-200-2009-001-CMD)

[10] California Energy Commission, June 2007, *Staff Forecast of 2008 Peak Demand*, CEC-400-2007-006-SF.

56 years of predicted annual peaks provide a distribution of possible peak demands under the weather conditions that have been observed since 1950. The median of the predicted annual peaks is the weather-normalized, "1-in-2," peak demand. Peak demand at the 90th percentile of the distribution is the 1-in-10 peak demand.

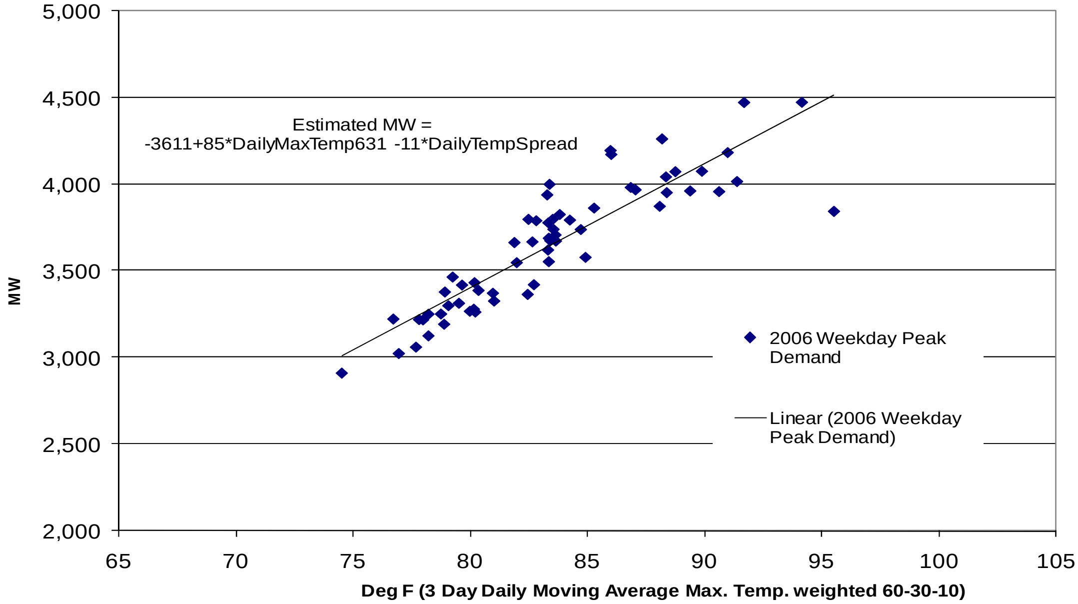
To calculate a distribution of summer 2009 peak demand possibilities, staff applied the estimated temperature response to the 2009 1-in-2 peak demand. For example, if the weighted average temperature assumed in the 1-in-2 demand forecast for SP 26 is 98 degrees and the weighted average temperature in 1976 was 101, the resulting 2009 peak demand increase using 1976 temperature data would be 1,467 MW ((404+85) * (101-98)) for the SP 26 region. Staff applied the change in demand for each recorded peak temperature over the 56 year period to develop a peak demand distribution. The resulting probabilistic graph for Southern California is presented in **Figure 6**. The chart characterizes the probability of aggregated load occurring for the whole Southern California region.

Figure 4: SCE 2006 Load versus Temperature



Source: California Energy Commission Demand Analysis Office

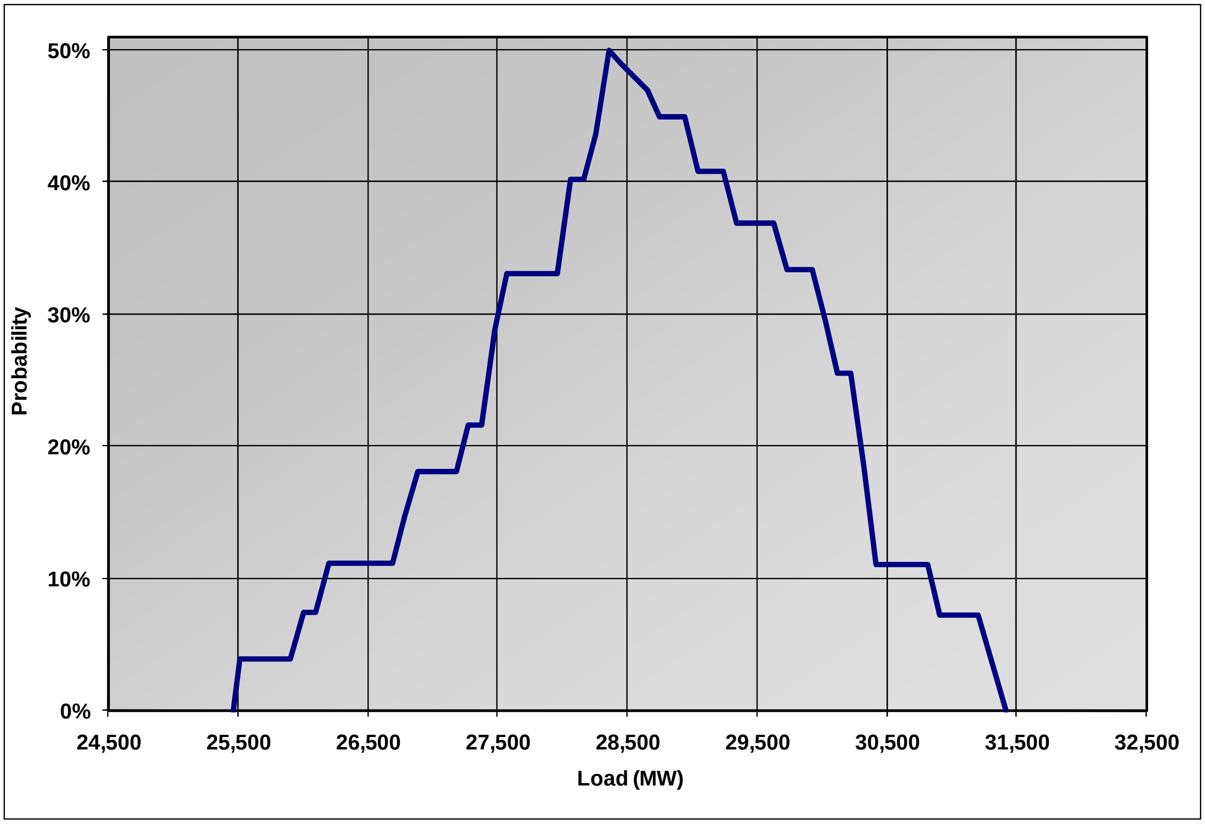
Figure 5: SDG&E 2006 Load versus Temperature



Source: California Energy Commission Demand Analysis Office

Figure 6 shows that the range of SP 26 demand in 2009 could be as low as 25,460 MW or as high as 31,350 with a 'most likely' demand of 28,391 MW. While the forecast could equally be higher or lower than the mean, the risks associated with the higher options are more relevant for planning considerations.

Figure 6: Probability of Demand California ISO SP 26 Summer 2009



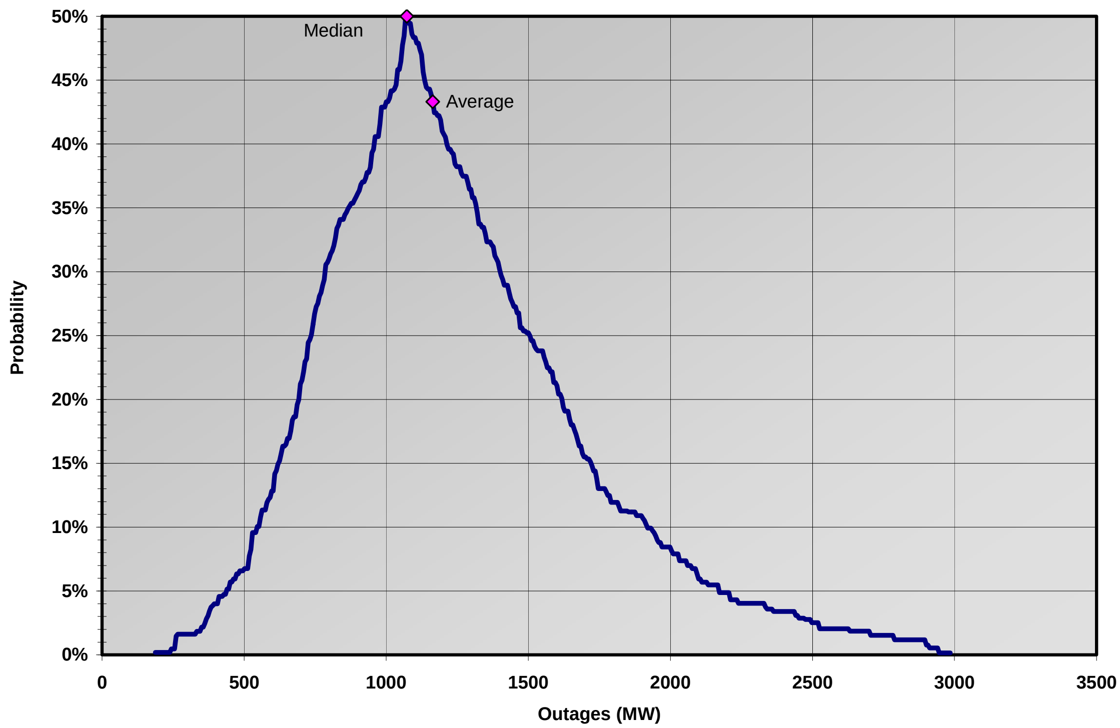
Source: Energy Commission Staff

Probability of Generation Forced Outages

Similar to the impact and range of possible demand, the magnitude of the total available resources can be expected to fall within a range of uncertainty due to the variation in forced outages. The Energy Commission staff calculated potential 2009 outages using actual 2002 through 2007 daily outage totals for the summer peak period provided by the California ISO. This set of data was statistically processed, and the results are presented in **Figure 7**.

Figure 7, shows the range of SP 26 forced outages in 2009 could be as low as 190 MW or as high as 2,990 MW, with a 'most likely' outage ouctcome of 1,075 MW. Again, the risks associated with the higher outages are the more relevant factors for resource planning considerations. The staff estimates a 10 percent probability that forced outages will be as high as 1,915 MW, and a 3 percent probability that they will be as high as 2,450 MW.

Figure 7: Probability of Generation Forced Outages California ISO SP 26 Summer 2009



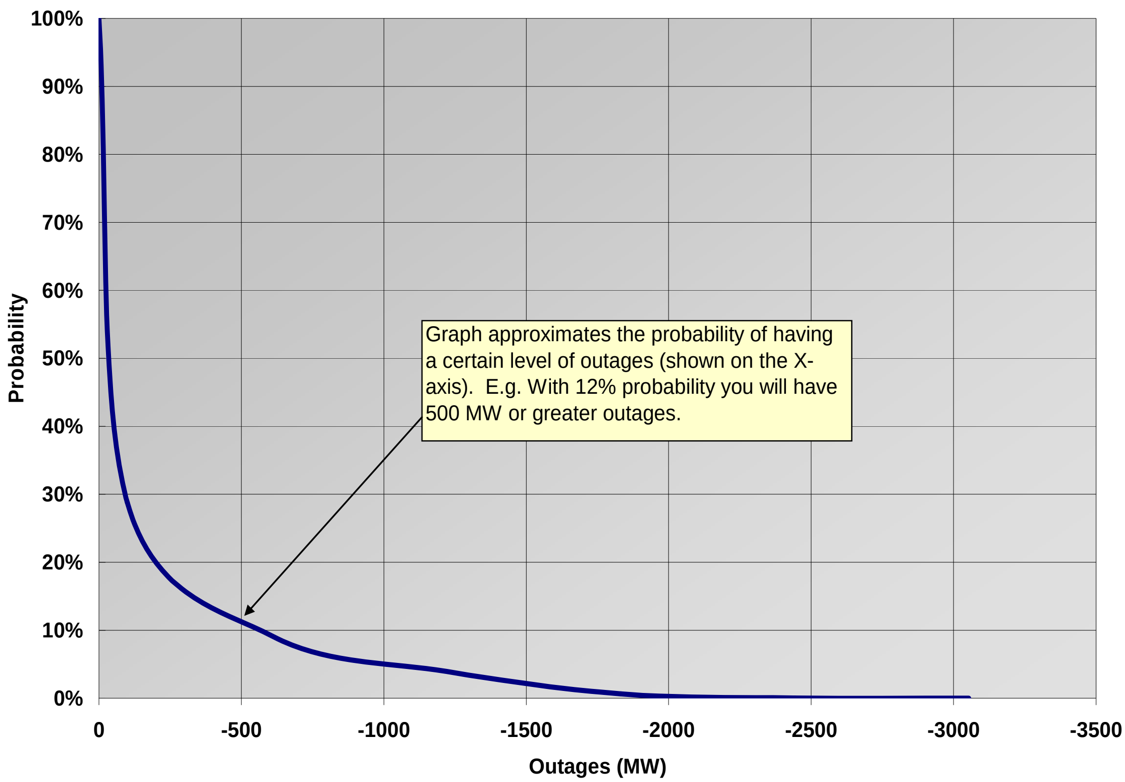
Source: Energy Commission Staff

Probability of Transmission Line Forced Outages

A major transmission line outage can also have significant impacts on the overall operation of the system. These outages often occur with little or no warning and, in the case of the Pacific DC Intertie (PDCI), can account for as much as a 2,000 MW reduction in resources available to meet load. On August 25, 2005, the PDCI unexpectedly dropped out of service just as Southern California was approaching its daily peak load. This outage, coupled with a 2,000 MW deviation in the day-ahead peak demand forecast, required the California ISO to issue a Transmission Emergency notice requesting utilities in SP 26 to reduce demand by curtailing 900 MW of firm load and 800 MW of voluntary interruptible load for about 35 minutes.

The staff included the effects of major transmission outages in the probabilistic analysis for this report. To calculate the overall impact of these failures on the SP 26 region, the staff used data obtained via subpoena from the California ISO to compare hourly transfer capacities with the WECC rating for each transmission line. One limitation of using this methodology is that it may omit short duration outages that are not visible at the time the transfer capacity is reported. For example, a line that trips off at five minutes after the hour and is restored 50 minutes later would not be visible in the dataset. **Figure 8** provides the range of transmission outages observed from May 15 through September 15 for the years 2003 through 2006.

Figure 8: Probability of Transmission Line Forced Outages California ISO SP 26 Summer 2009



Source: Energy Commission Staff

Probability of Maintaining Minimum Required Operating Reserves

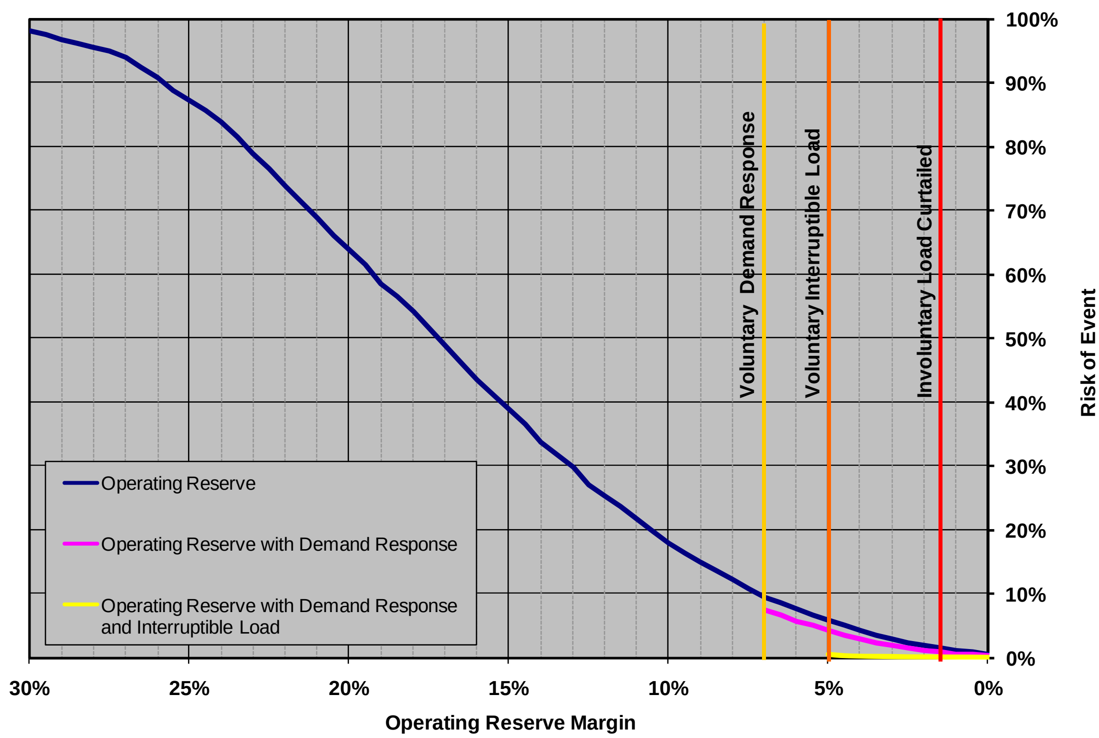
Calculating generation and transmission availability and comparing the sum against a complete range of electricity demand results in a probabilistic assessment of resource adequacy. Using the Monte Carlo method, 5,000 cases of different resource and demand scenarios are developed for summer 2009. Each case is then reviewed to determine whether resources are sufficient to meet demand plus minimum operating reserves. The SAM-A model conducts the calculations in the following four major steps:

- Using Monte Carlo draws, the model generates a deterministic case of input data in which each uncertainty factor takes a random value from its respective range of possible values.

- Evaluation of the adequacy of supply is made for each deterministic case using spreadsheet tables.
- The above steps are repeated for multiple cases to reasonably cover all possible combinations of the values of the uncertain factors.
- The resulting set of cases is statistically processed to calculate:
  - The probability that there is insufficient capacity to meet the peak demand and maintain a given reserve margin.
  - The probability that there is sufficient capacity to meet the peak demand and maintain a given reserve margin.

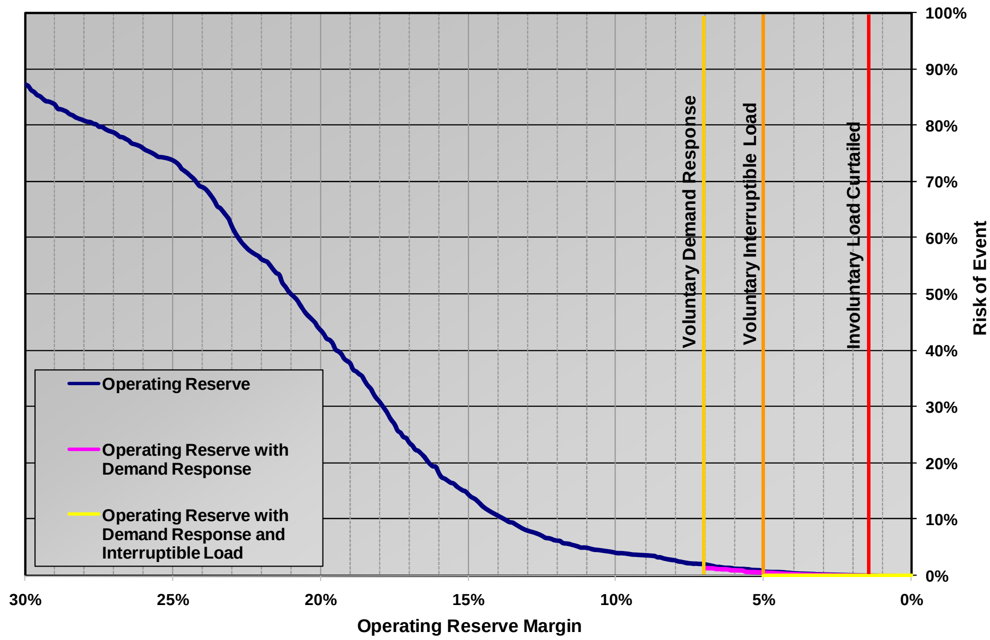
Figure 9, **Figure 10**, and **Figure 11** provide the probabilities for dropping to the minimum operating reserve margin levels for each of the three studied regions.

Figure 9: Operating Reserve - California ISO Summer 2009



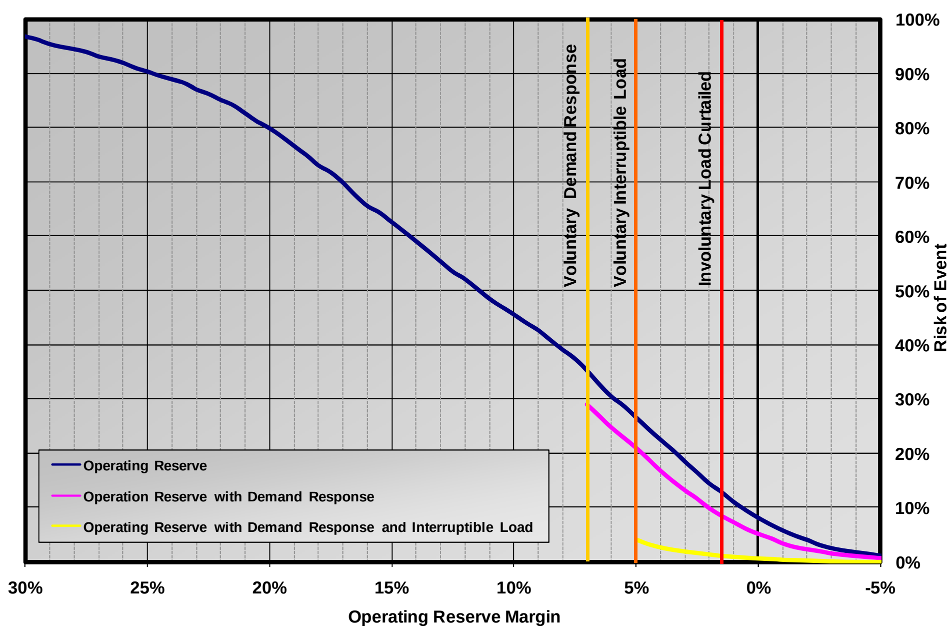
Source: Energy Commission Staff

Figure 10: Operating Reserve - California ISO NP 26 Summer 2009



Source: Energy Commission Staff

Figure 11: Operating Reserve - California ISO SP 26 Summer 2009

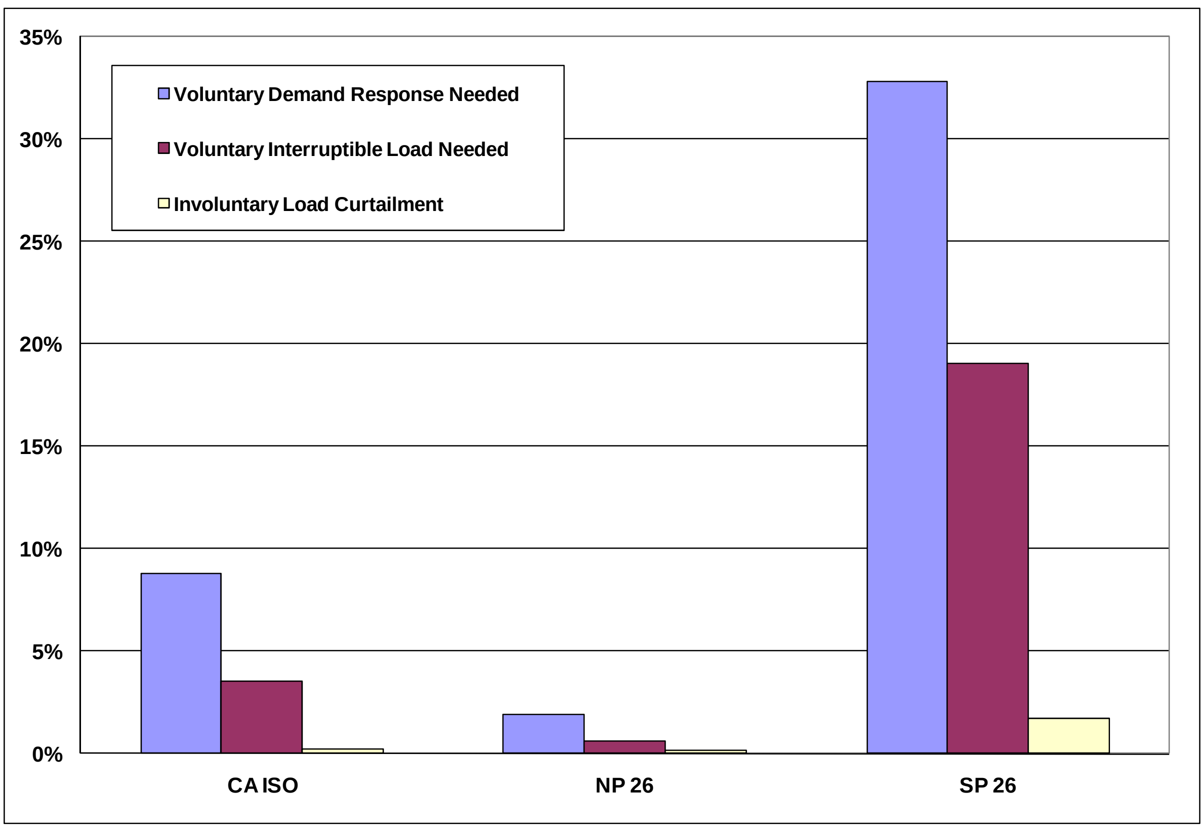


Source: Energy Commission Staff

Figure 12 provides a snapshot of the critical points identified in **Figures 9 through 11** for each of the three regions on the peak day of summer 2009. The results also can be interpreted in terms of risk. The staff assessment shows that there is a very low risk of involuntary load curtailments (Stage 3 Emergency at 1.5 percent operating reserves) in the California ISO and NP 26 regions. The staff completed risk calculations for operating reserve margins dropping to 3 percent (high end of Stage 3 Emergency alert) and found the SP 26 probability of events increased to 1.7 percent. The probability of events for the California ISO and NP26 at the 3 percent reserve margin levels remained very low, each below 0.25 percent. The risk of curtailing firm load remains higher in the SP 26 region, but shows substantial improvement relative to the 2008 outlook. Collectively, these risks are likely to continue to diminish in the near term.

The likelihood of utilizing voluntary demand response and interruptible load programs is much higher in SP 26. This may be considered an acceptable risk level since the customers enrolled in these programs receive preferential rates or other incentives to provide an extra level of mitigation during peak load conditions.

Figure 12: Risk of Event on the Summer 2009 Peak Day



Source: Energy Commission Staff

APPENDIX A: Detailed Assumptions Used to Calculate Planning Reserve Margins

Electricity Supply Adequacy Criteria

The Energy Commission studies potential long-term (10 years) electricity supply and demand conditions to ensure that California maintains a sustainable and reliable energy system into the future. The Energy Commission also analyzes short-term market developments and a range of potential system variations to determine if there are any significant risks of potential supply shortfalls during the upcoming peak demand season. This analytical activity became particularly important following the 2000-2001 energy crisis experiences.

For a small number of hours, the generation capacity that sits idle for most of the year is needed to meet peak demand. Electricity use varies widely over the time of day and time of year. On a typical day, demand increases 60 percent from the midnight low to the afternoon high. Because air conditioning loads drive peak demand, California sees its greatest demand spikes during the summer months (June, July, August, and September). On a hot summer day, this swing can be 85 - 90 percent. The difference in demand between an average summer day and a very hot peak day is 6 percent. This difference is equivalent to three years' average growth in statewide electricity demand. This variable demand trend requires a generation system that is extremely flexible. The full available capacity of the system needs to be dispatched only to meet a few hours of peak demand each summer.

The electricity supply assessment for the summer peak demand season includes evaluating existing reserves that serve as a buffer for unplanned fluctuations, and analyzing the probabilities that a system emergency may occur. A reserve margin is a measure of the amount of electricity imports and in-state generation capacity available over average peak demand conditions. Reserve margins are measured at two levels: planning and operating.

A specified planning reserve margin target is the level necessary to cover a particular range of possible system fluctuations and unexpected emergencies. The target is based on the possibility that a loss of load would occur no more frequently that one day in ten years, which translates into a 15 to 17 percent planning reserve margin. Rare conditions will occur, such as the 2006 summer temperatures that caused a simultaneous spike in electricity demand throughout California and the West. Even though this 1-in-30 year event topped out above the range of uncertainties established for the planning reserve margin target, sufficient electricity imports and generation supplies avoided any customer curtailments.

A planning reserve margin that is too low may result in a higher chance of customer curtailments. A target reserve margin that is too high may dampen generation and transmission investment incentives, cost more than consumers are willing to pay for the risk of an outage, and frustrate new development (including renewables and demand response) that depends on evolving regulatory decisions. Increasing the planning reserve margin to cover a larger range of contingencies would require more generation and transmission facilities to be built which could stand idle until the rare event occurs. The goal is to balance the risks of outages and overall costs to maintaining a redundant system.

An operating reserve margin is the amount of imports and actual ("spinning") generation above current demand, and represents real-time operations that fluctuate minute to minute.[11] The operating margin is the target buffer that is assumed to be sufficient for control area operators to deal with immediate emergencies or fluctuations in electricity demand, such as hotter than predicted day-ahead temperatures, and/or generation, such as unplanned maintenance. The regional North American Electric Reliability Councils (NERC) establishes Minimum Operating Reserve Criteria (MORC) that is necessary to maintain system reliability. The Western Electricity Coordinating Council is the regional body that evaluates the MORC levels for all west coast system operators.

The minimum operating reserve criteria target is approximately 7 percent, but varies depending on the portfolio mix of generation resources. To be counted as part of the operating reserves, conventional generation facilities must be ready to generate electricity when needed. Hydro-generation systems only require a 5 percent operating reserve target since these facilities can generate electricity on a moment's notice. Electricity imports are usually backed up by the operating reserves within the source region.

Factors Used to Determine Planning Reserve Margins

Table A-1 thru **A-7** provide a more detailed description of the data and assumptions used to calculate the planning reserve margin in the *Summer 2009 Electricity Supply and Demand Outlook*.

Existing Generation

Existing generation accounts for thermal and hydro generation facilities operational as of August 1, 2008, plus new generation already online or expected to be online prior to June 1, 2009. Thermal generation consists of California ISO control area merchant and municipal thermal resources (including non-hydro renewable), Investor-Owned Utility (IOU) retained

[11] This does not include the generation that is not scheduled to operate, shut down for planned maintenance, unexpected failure outages, or unable to be delivered due to transmission problems. Actual demand levels may also be higher than expected when generation was scheduled to operate the day before and result in a shortfall in operating power plant supply.

generation,[12] and Qualifying Facilities (QFs). Merchant thermal generation capacity in SP 26 includes 1,080 MW of contracted capacity from units located in Baja California Norte.

Thermal unit capacity is derated to reflect summer operating conditions, and this summer derating can range from 90 to 96 percent of nameplate capacity based on the type of unit considered and its geographic location. The derated value is termed "dependable capacity." The Non-California ISO generation totals include both thermal and hydro capacity. **Table A-1** shows additions of generation capacity since September 1, 2008, and that expected to be added by June 1, 2009.

Table A-1: 2009 Derated Generation

		SP26	NP26	TOTAL
CA ISO Control Area				
As of 9/1/08	Thermal & QF	21,230	19,140	40,370
As of 9/1/08	Derated Hydro	1,047	5,942	6,989
TOTAL CA ISO as of 9/1/08		**22,277**	**25,082**	**47,359**
Non-CA ISO as of 9/1/08		6,555	4,996	11,551
STATEWIDE TOTAL as of 9/1/08				**58,910**
CA ISO Control Area				
Added between 9/1/08 and 6/2/09	Thermal & QF	650	370	1,020
Added between 9/1/08 and 6/2/09	Derated Hydro	0	0	0
TOTAL CA ISO added 9/1/08 - 6/1/09		**650**	**370**	**1,020**
Non-CA ISO added 9/1/08 - 6/1/09		0	0	0
STATEWIDE TOTAL added 9/1/08 - 6/1/09				**1,020**
CA ISO Control Area				
As of 6/1/09	Thermal & QF	21,880	19,510	41,390
As of 6/1/09	Derated Hydro	1,047	5,942	6,989
TOTAL CA ISO as of 6/1/09		**22,927**	**25,452**	**48,379**
Non-CA ISO as of 6/1/09		6,555	4,996	11,551
STATEWIDE TOTAL as of 6/1/09				**59,930**

Source: Energy Commission Staff

Hydroelectric Dependable Capacity

The 6,989 MW of available capacity that is included in **Table A-1** does not include "imports" delivered to the California ISO from the Western Area Power Administration from federal Central Valley Project hydro plants at Lake Shasta, Trinity Reservoir, Folsom Lake, New Melones, Millerton Lake, and elsewhere. The California ISO dependable hydro capacity

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[12] Retained generation include the facilities that were not sold by the IOUs when the California electricity market was restructured in the late-1990s.

estimate is based on an analysis of low water year conditions, similar to expected conditions this upcoming summer. This conclusion is supported by physical systems assessment, by historical performance, and by utilities' filings that demonstrate they have adequate resources to serve peak summer loads.

Dependable hydro capacity at peak does not significantly change between wet and dry water years even though the historic record shows that dry conditions can have a significant impact on available energy production. In a wet or average year, about 8,000 MW of hydroelectric generating capacity is connected to the high voltage grid managed by the California ISO. For dry year conditions, expected to occur once every five years, a conservative number for hydro capacity would be about 7,000 MW. If dry conditions continue for a third consecutive year, a small additional derate may become evident. Generating performance of these resources during the two-year drought in 1976-1977 and multi-year event between 1986-1992 show that an additional derate of more than 100 MW is a warranted assumption.

In California, hydroelectric generating capacity is not significantly diminished (or derated) when less water is available. Most utility-owned hydro capacity is located far below storage reservoirs. Water from high elevation reservoirs is typically delivered to these power plants by flumes, tunnels, and then penstocks to power plants at a much lower elevation, sometimes hundreds of feet below in a distant canyon. Where utility power plants are located at a dam site, most utility-managed reservoirs are kept full to meet daily, weekly, and annual peak loads.

At most hydropower facilities in California, water is dependably delivered to each powerhouse when it is most valuable. Based on assessments of loads and resources, Energy Commission staff and utility hydrologists currently are not concerned about potentially extreme reductions hydropower capacity.

Generation Additions and Retirements

Table A-2 provides a listing of the dependable capacity of all additions and retirements included in the *2009 Outlook*. These are additions and retirements that occurred since August 31, 2008, or that are believed to have a high probability of taking place prior to August 1, 2009. The statewide aggregate totals 1,419 MW of capacity added statewide during that timeframe.

Table A-2: 2009 Additions and Retirements

California ISO Control Area					
SP26			**NP26**		
SP 26 Additions			***NP 26 Additions***		
Name	**MW**	**Expected or On-Line**	**Name**	**MW**	**Expected or On-Line**
Inland Empire (U1 & STG)[13]	370	Jan	Gateway	530	Feb
			Starwood-Midway	120	May
			EIF Panoche[14]	399	Aug
SP 26 Retirements			***NP 26 Retirements***		
Name	**MW**	**Month**	**Name**	**MW**	**Month**
-	0	**-**	**-**	0	**-**
Aggregate SP 26	**370**		**Aggregate NP 26**	**1,049**	
Aggregate California ISO Control Area: 1,419 MW					
Non-California ISO Control Area					
LADWP & IID Control Areas			**SMUD & TID Control Areas**		
LADWP & IID Additions			***SMUD & TID Additions***		
Name	**MW**	**Expected or On-Line**	**Name**	**MW**	**Expected or On-Line**
-	0	**-**	**-**	0	**-**
LADWP & IID Retirements			***SMUD & TID Retirements***		
Name	**MW**	**Month**	**Name**	**MW**	**Month**
-	0	-	-	0	-
Aggregate LADWP & IID	**0**		**Aggregate SMUD & TID**	**0**	
Aggregate Non-California ISO Control Area: 0 MW					
Aggregate Statewide	**1,419 MW**				

Source: Energy Commission Staff

[13] The Inland Empire Energy Center was certified by the Energy Commission in 2003. The combustion turbine generators (CTG) are rated at 180 MW each, and the steam turbine generator (STG) at 204 MW, for a total rated capacity of 564 MW (nameplate capacities). With supplementary duct firing and steam injection, the peak plant output increases to 670 MW. The 370 MW capacity value for CTG1 and the STG combination is an estimate of the minimum that can be expected over the summer (*Final Staff Assessment*, Air Quality Section, p. 5.1-15, issued May 23, 2003.)

[14] EIF Panoche is expected to be providing electricity to the grid prior to August 1, the date published by the Energy Commission. (http://www.energy.ca.gov/sitingcases/all_projects.html, accessed March 17, 2009, and personal discussion between D. Rundquist, Energy Commission Compliance Project Manager, and M. Pryor on March 17.) Should a delay occur, the lowest 1-in-2 projected reserve margin in either NP 26, California ISO or Statewide during August and September would be 25.5 percent for the Statewide value and would be expected to occur in August. This represents a reserve margin that is 0.7 percent less than what is projected with EIF Panoche contributing to the system. The lowest 1-in-10 projected reserve margin would be 18.8 percent (0.6 percent) less, also for Statewide in August.

Newly Operational, Delayed, Cancelled or Changed Generation

There have been numerous changes to the *2008 Outlook's* listing of expected power plants:

Achieved Commercial Operations

- As expected, Imperial Irrigation District's 90 MW Niland Gas Turbine Plant achieved commercial operations in May 2008.[15]

Delays and Cancellations

- General Electric's Inland Empire Energy Center (IEEC) suffered a major failure of the plant's number two combustion turbine generator (CTG) in August 2008. This almost coincided with a separate problem involving the other combustion turbine generator, CTG1. Both units were delayed until the cause of CTG2's failure was ascertained, and whether CTG1 was susceptible to a similar problem. The turbine manufacturer determined CTG2's failure was unit-specific and on January 26, 2009, CTG1 and the steam turbine generator (STG) were available for California ISO dispatch, with a capacity of about 370 MW. CTG2 is expected to be operational in October. When CTG2 is operational, the entire project will be evaluated for commercial operations. Until commercial operations are attained, the project will only be "dispatchable."[16]
- Imperial Irrigation District's replacement of the existing El Centro 44 MW boiler by the new 128 MW combustion turbine generator was expected to take place by June 1, yielding an aggregate addition of 84 megawatts. The project is now listed by the Energy Commission as "on hold."[17]
- Southern California Edison's proposed 44 MW Mandalay Peaker Unit Project in Oxnard has been delayed due to Coastal Commission concerns and has been dropped from listing for 2009.[18] Whether the project will eventually be approved and built is unknown.
- One generating project, Wellhead Margarita, was cancelled.[19]

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[15] http://www.iid.com/Media/niland_media_kit_08.pdf(Accessed January 28, 2009.)

[16] M. Pryor, personal conversation with the Energy Commission Compliance Project Manager, D. Rundquist, March 12, 2009.

[17] www.energy.ca.gov/sitingcases/all_projects.html Accessed March 12, 2009.)

[18] http://www.venturacountystar.com/news/2008/aug/08/decision-on-peaker-power-plant-put-off/ (Accessed January 30, 2009.)

[19] http://www.laderatimes.com/uploads/wellheadlegaldocument.pdf (Accessed January 30, 2009.)

Change in the Nature of the Project

One project not listed in the *2008 Outlook* as highly probable, the Orange Grove project, was filed with the Energy Commission in 2007 as a Small Power Plant Exemption (07-SPPE-1). This SPPE was withdrawn on April 28, 2008, and re-filed as an Application for Certification (09-AFC-4) on June 20, 2008. The Orange Grove AFC was certified ("licensing") by the Energy Commission on April 8, 2009, but it is not be expected to be commercially operational until after the summer.

Net Imports (Net Interchange)

The net import assumption represents a conservative estimate of potential electricity imports into each region and is based on the western United States/Canada/Mexico electricity system's capability to provide surplus generation during peak demand periods. The inter-connected and inter-dependent wholesale western power market provides reliability benefits as well as broad opportunities for cost savings due to the diverse mix of surplus electricity resources and different load patterns in each part of the western system. Electricity is imported from other western states, Canada and Mexico for various reasons, and involves different types of long-term and short-term transactions.

Some of the imported electricity is either generated at plants that are partially-owned by California utilities, or is purchased using long-term contracts. The amount of imports associated with these specified sources are relatively stable and do not vary from year-to-year.

The remaining electricity imports are generally acquired through short-term transactions that are traded on the western wholesale power market. These acquisitions represent almost half of the total annual imports of electricity. California utilities and generators purchase short-term market electricity to reduce costs, such as those associated operating more expensive generation facilities within California.

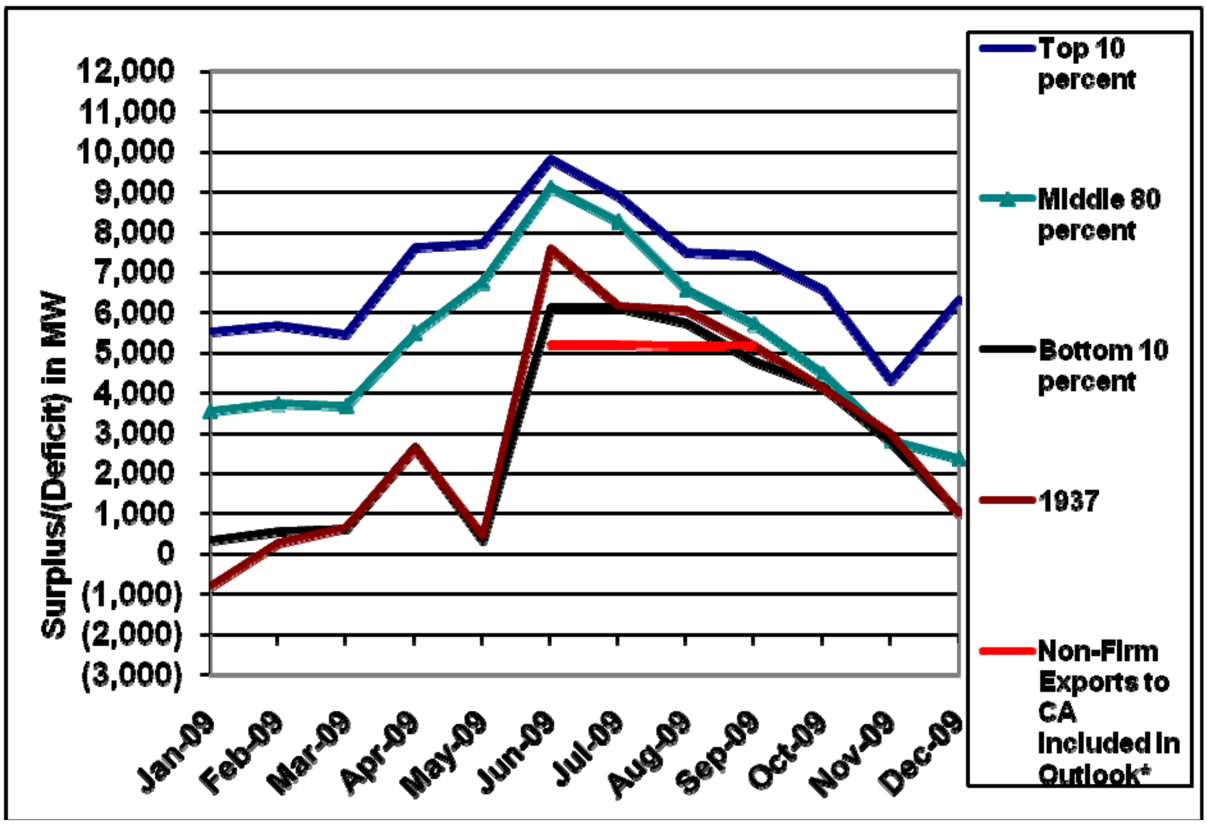
Short-term electricity purchases also occur to occasionally meet unexpected supply shortfalls due to higher-than-expected demand or facility outages. The California ISO will purchase short-term electricity supplies if a day's actual demand proves to be higher than the day-ahead forecast predicted, and for which an inadequate supply of generation was scheduled.

The amount of short-term imports may vary seasonally and usually depends on hydro-generation conditions in both California and the Pacific Northwest region. The amount of short-term imports may also vary day-by-day, depending on different market incentives or if there are operating constraints due to generator and/or transmission conditions. Energy Commission staff determined that there is a sufficient quantity of surplus capacity in neighboring regions to meet the net interchange estimates detailed below.

Figure A-1 provides a summary of the Bonneville Power Administration forecast of surplus capacity in the Northwest by various water conditions. Even in the driest year on record (1937), there is enough surplus capacity in the region to meet the interchange assumption included in the *2009 Outlook*.

The staff determined the amount of surplus resources in the Southwest by conducting internal modeling simulations and reviewing the most current Western Electricity Coordinating Council's *Power Supply Assessment* (November 5, 2008).

Figure A-1: 2009 Forecast of Northwest Regional Surplus/Deficit by Water Year



Source: Energy Commission Staff
Note: Based on 2006 BPA White Book 1-Hour Capacity in Megawatts

Net Import Details by Region

Tables A-3 through A-6 provide details on the individual components of net interchange for each of the four regions. Some imports are identified as capable of carrying their own reserves since transmission is the factor that limits capacity exchange, and there is sufficient surplus to replace a generation outage from the exporting region.

The Los Angeles Department of Water and Power (LADWP) Control Area interchange values provided in **Tables A-3 and A-4** include power that is wheeled through the LADWP Control Area to other municipal utilities served by the California ISO. **Table A-5** reflects an export level on Path 26 of 1,500 MW at time of NP 26 peak load conditions.

Table A-3: Statewide Net Interchange

Northwest Imports over the California-Oregon Intertie (COI)[20]	4,000
Southwest Imports	4,100
Pacific DC Intertie (California ISO)	2,000
LADWP and IID Control Areas	3,018
Total	**13,118**

Table A-4: California ISO Net Interchange

California ISO Share of NW Imports (COI)	2,300
WAPA Central Valley Imports	950
Southwest Imports	4,100
Pacific DC Intertie (California ISO)	2,000
Net LADWP Control Area Interchange	1,000
Total	**10,350**

Table A-5: NP 26 Net Interchange

California ISO Share of NW Imports	2,300
WAPA Central Valley Imports	950
Path 26 Exports	(1,500)
Total	**1,750**

Table A-6: SP 26 Net Interchange

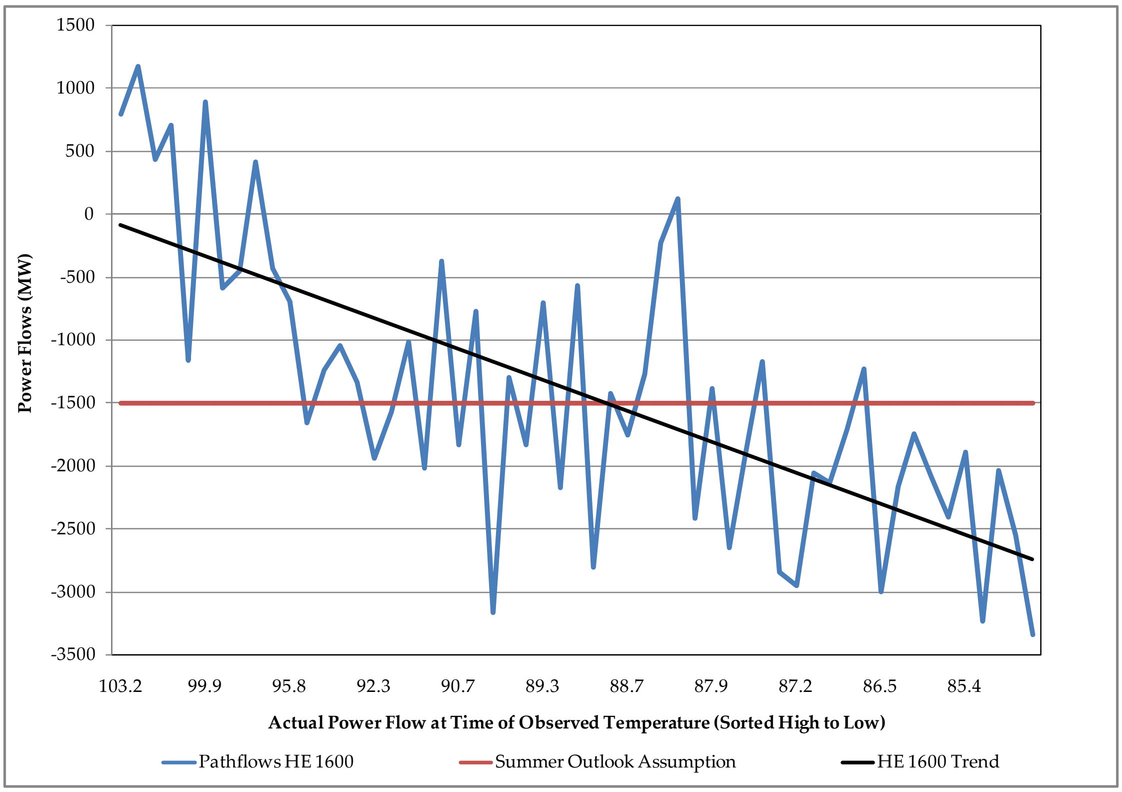
Path 26	3,000
California ISO Share of Pacific DC Intertie	2,000
Net SW Imports	4,100
Net LADWP Control Area Interchange	1,000
Total	**10,100**

Source: Energy Commission Staff

[20] Imports assumed to carry reserves as transmission is the limiting factor.

Figure A-2 provides the actual weekday power flows on Path 26 for the hour ending 1600 during summer 2008, sorted by the observed temperature in Northern California. Negative numbers indicate North-to-South flows and positive numbers are South-to-North. There is a wide range of variation in the flows over the entire summer period; however, there is clearly a trend of less power flowing from North to South on Path 26 during periods of higher temperature conditions in Northern California. Additional detailed analysis is available in the Commission Staff Paper, *Revisiting Path 26 Power Flow Assumptions* (October 2008).

Figure A-2: Summer 2008 Path 26 Weekday Flows (MW)
Sorted by Temperature (°F)
(Negative number indicates North-to-South)



Source: Energy Commission Staff

Northern California has historically observed peak temperatures and load during the month of July in contrast to Southern California, which peaks in late August or early September. This load diversity between the two regions results in different import/export values when comparing **Tables A-5** and **A-6**. **Table A-6** includes 3,000 MW of Path 26 North to South. The export from North to South at either level reflects the greater need of capacity in SP 26 than NP 26, but does not imply that it is contractually obligated to be delivered into SP 26.

1-in-2 Summer Temperature Demand (Average)

The peak demand forecast for the *2009 Outlook* is the current adopted Energy Commission demand forecast.[21] Complete documentation of assumptions and methodologies are included in those reports.

Interruptible and Demand Response Resources

There are several mitigation measures available to the California ISO and individual utilities to respond to adverse conditions when operating reserves fall below minimum acceptable levels. **Table A-7** details the expected impacts from IOU demand response and interruptible programs that are established at the CPUC and/or have been contracted by an IOU. There is also an additional 110 MW of demand response from pumping load in SP 26 that is not included in the CPUC filings but included in **Table A-7** as Special Contracts.

These estimated impacts were developed to support implementation of 2009 resource adequacy requirements for CPUC-jurisdictional LSEs. CPUC and Energy Commission staff reviewed and revised the projected impacts to ensure that impacts are calculated consistently with the load impact estimation protocols developed in the CPUC demand response proceeding, and that projected enrollments are reasonable. A detailed explanation of the demand response programs identified in **Table A-7** follows.

Interruptible Load Programs

Interruptible resources are composed primarily of two general types of programs: interruptible rates and direct control. In interruptible rate programs the customer receives discounted energy and demand charges for load subject to curtailment during system events. Because customers are subject to non-compliance penalties if demand is above the contracted firm service level during events, the compliance rate in recent years has been 95 percent or better.

Direct control programs are those in which the utility can control the operation of customer's equipment. For example, customers receive a bill credit if they allow the IOU to temporarily turn-off or "cycle" their central air conditioner compressor during periods of peak demand. The PG&E interruptible resources also include 200 MW of dispatchable load provided by California Department of Water Resources during summer months.

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[21] Forecasts for the CA ISO regions are documented in *Revised 2010 Peak Demand Forecast*, (Energy Commission 2009 CEC-200-2009-001-CMD). Forecasts for the rest of state are documented in California Energy Commission, 2007, *California Energy Demand 2008-2018: Staff Revised Forecast*, CEC-200-2007-015-SF2.

Table A-7: 2009 Demand Response and Interruptible Load Resources

	Expected MW			
PG&E	**June**	**July**	**August**	**September**
Interruptible Rates	501	503	512	508
Direct Control	152	152	152	152
Total Interruptible	**653**	**655**	**663**	**660**
Critical Peak Pricing	11	12	12	13
Demand Bidding	28	28	28	28
Demand Response Aggregators	87	89	89	91
Total Demand Response	**127**	**128**	**130**	**131**
Total NP 15	**780**	**784**	**793**	**791**
SCE	**June**	**July**	**August**	**September**
Interruptible Rates	651	651	651	651
Direct Control	614	614	614	614
Total Interruptible	**1,265**	**1,265**	**1,265**	**1,265**
Critical Peak Pricing	12	12	12	12
Other DR (Demand Bidding, RTP)	57	57	57	57
Demand Response Aggregators	56	67	72	72
Total Demand Response	**125**	**136**	**141**	**141**
Special Contracts	**110**	**110**	**110**	**110**
SDG&E	**June**	**July**	**August**	**September**
Interruptible Rates	3	3	3	3
Direct Control	15	15	15	15
Total Interruptible	**18**	**18**	**18**	**18**
Critical Peak Pricing	49	49	49	49
Demand Bidding	24	24	24	24
Demand Response Aggregators	0	0	0	0
Total Demand Response	**73**	**73**	**73**	**73**
Total SP26	**1,591**	**1,602**	**1,606**	**1,606**
Total California ISO	**2,370**	**2,385**	**2,399**	**2,397**
Non-California ISO Resources	**200**	**200**	**200**	**200**
Total Statewide	**2,570**	**2,585**	**2,599**	**2,597**

Source: Energy Commission Staff

Demand Response Programs

Demand response programs employ a variety of incentive structures to motivate peak demand reduction, and do not have penalties for noncompliance.

Critical Peak Pricing rates offer discounts (energy, demand or both, depending on the particular design) in non-critical hours but charge a premium for energy consumed on a limited number of days when system conditions are forecast to be critical, typically due to high expected demand or supply shortfalls.

In Demand Bidding Programs, participants are paid an incentive for load reductions during curtailment events that are “bid” in to the utility in advance. There is no penalty for not bidding or not fulfilling the bid obligation. These programs have a much lower performance rate (in terms of MW reduced per subscribed MW) than interruptible programs, and the estimated impacts reflect that. The SCE impacts also include 25 MW from a Real Time Pricing (RTP) tariff in which participants are charged hourly electricity prices driven by temperature. The projected load impact is based on estimated 2008 load reductions on a hot day compared to a mild day.

Demand Response Aggregators are contractors who develop their own demand response programs and provide load reductions to the IOU. When the IOU calls an event, the aggregators are responsible for dropping electrical load on an aggregated portfolio basis equal to their contracted amount.

APPENDIX B: A COMPARISON OF TWO METHODOLOGIES FOR CALCULATING PLANNING RESERVE MARGINS

Planning Reserve Margin Calculation

There are two general methods of calculating Planning Reserve Margins (PRMs). The method staff uses in *Summer Outlooks* treats demand response, interruptible and curtailable program capacities as additions to total net generation. The second method treats capacities from these programs as reductions in demand. This method was used in a recent Energy Commission staff draft paper to be consistent with Southern California Edison resource procurement calculations. [22] The following is an evaluation to determine if the methodologies have different PRM results. The equations used to derive PRMs under each method are:

Method 1

$$PRM\ (\%) = \left[\frac{Total\ Net\ Generation + Interruptibles + Curtailables}{Demand}\right] - 1$$

Method 2

$$PRM\ (\%) = \left[\frac{Total\ Net\ Generation}{Demand - (Demand\ Response + Interruptibles + Curtailables)}\right] - 1$$

The evaluation shows that the differences are small. Staff continues to use the first method because it yields a slightly more conservative result.

Table B-1 compares the results of the two methodologies and shows that differences for each region are larger for 1-in-2 conditions, ranging from 1.0 percent for the Statewide reserve margin in August to 2.6 percent for SP 26 in June. The 1-in-10 conditions range from 0.6 percent for both Statewide and SP 26 in August, to 1.3 percent in SP 26 in June and NP 26 in September. These ranges may be within margins of error for any of the variables, or combinations thereof; however, staff did not determine whether this is the case.

[22] Staff Draft Paper, *Potential Impacts of the South Coast Air Quality Management District Air Credit Limitations and Once-Through Cooling Mitigation on Southern California's Electricity System*, issued February 2009. CEC-200-2009-002-SD

Table B-1: Comparison of 2009 Reserve Margin Methodologies

	2009			
	Jun	Jul	Aug	Sep
SP26				
Total Net Generation	33,027	33,027	33,027	33,027
DR+IR	1,591	1,602	1,606	1,606
1-in 2 Demand	24,453	26,545	28,391	26,475
1-in-10 Demand	27,846	28,828	30,673	30,009
DR+IR as a Resource				
TNG+DR+IR	34,618	34,629	34,633	34,633
1-in-2 Res PRM[1]	41.6%	30.5%	22.0%	30.8%
1-in-10 Res PRM[1]	24.3%	20.1%	12.9%	15.4%
DR+IR as Demand Reduction				
1-in-2 Demand-(DR+IR)	22,862	24,943	26,785	24,869
1-in-2 DR PRM[2]	44.5%	32.4%	23.3%	32.8%
1-in-10 Demand-(DR+IR)	26,255	27,226	29,067	28,403
1-in-10 DR PRM[2]	25.8%	21.3%	13.6%	16.3%
Diff. DR PRM >Resource PRM				
1-in-2	2.9%	2.0%	1.3%	2.0%
1-in-10	1.5%	1.2%	0.7%	0.9%
NP26				
Total Net Generation	27,202	27,202	27,601	27,601
DR+IR	780	784	793	791
1-in 2 Demand	20,371	21,954	20,530	19,518
1-in-10 Demand	22,222	22,760	21,868	21,328
DR+IR as a Resource				
TNG+DR+IR	27,982	27,986	28,394	28,392
1-in-2 Res PRM[1]	37.4%	27.5%	38.3%	45.5%
1-in-10 Res PRM[1]	25.9%	23.0%	29.8%	33.1%
DR+IR as Demand Reduction				
1-in-2 Demand-(DR+IR)	19,591	21,170	19,737	18,727
1-in-2 DR PRM[2]	38.8%	28.5%	39.8%	47.4%
1-in-10 Demand-(DR+IR)	21,442	21,976	21,075	20,537
1-in-10 DR PRM[2]	26.9%	23.8%	31.0%	34.4%
Diff. DR PRM >Resource PRM				
1-in-2	1.5%	1.0%	1.5%	1.9%
1-in-10	0.9%	0.8%	1.1%	1.3%

[1] Res PRM = [(TNG+DR+IR)/Demand]-1

[2] DR PRM = [TNG/(Demand-(DR+IR)]-1

[3] Includes 310 MW of for non-CA ISO interruptible programs.

Table B-1: Comparison of Reserve 2009 Margin Methodologies (cont.)

	2009			
	Jun	Jul	Aug	Sep
CA ISO				
Total Net Generation	58,729	58,729	59,128	59,128
DR+IR	2,370	2,385	2,399	2,397
1-in 2 Demand	44,824	48,499	48,921	45,993
1-in-10 Demand	50,068	51,588	52,541	51,337
DR+IR as a Resource				
TNG+DR+IR	61,099	61,114	61,527	61,525
1-in-2 Res PRM[1]	36.3%	26.0%	25.8%	33.8%
1-in-10 Res PRM[1]	22.0%	18.5%	17.1%	19.8%
DR+IR as Demand Reduction				
1-in-2 Demand-(DR+IR)	42,454	46,114	46,522	43,596
1-in-2 DR PRM[2]	38.3%	27.4%	27.1%	35.6%
1-in-10 Demand-(DR+IR)	47,698	49,203	50,142	48,940
1-in-10 DR PRM[2]	23.1%	19.4%	17.9%	20.8%
Diff. DR PRM > Resource PRM				
1-in-2	2.0%	1.3%	1.3%	1.9%
1-in-10	1.1%	0.9%	0.8%	1.0%
Statewide				
Total Net Generation	73,048	73,048	73,447	73,447
DR+IR[1]	2,570	2,585	2,599	2,597
1-in 2 Demand	55,861	60,924	61,623	57,898
1-in-10 Demand	62,116	65,150	65,811	64,330
DR+IR as a Resource				
TNG+DR+IR	75,618	75,633	76,046	76,044
1-in-2 Res PRM[1]	35.4%	24.1%	23.4%	31.3%
1-in-10 Res PRM[1]	21.7%	16.1%	15.6%	18.2%
DR+IR as Demand Reduction				
1-in-2 Demand-(DR+IR)	53,291	58,339	59,024	55,301
1-in-2 DR PRM[2]	37.1%	25.2%	24.4%	32.8%
1-in-10 Demand-(DR+IR)	59,546	62,565	63,212	61,733
1-in-10 DR PRM[2]	22.7%	16.8%	16.2%	19.0%
Diff. DR PRM > Resource PRM				
1-in-2	1.7%	1.1%	1.0%	1.5%
1-in-10	0.9%	0.7%	0.6%	0.8%

[1] Res PRM = [(TNG+DR+IR)/Demand]-1

[2] DR PRM = [TNG/(Demand-(DR+IR)]-1

[3] Includes 310 MW of for non-CA ISO interruptible programs.

Source: Energy Commission Staff

APPENDIX C: COMPARISON OF PLANNING RESERVE MARGINS ASSUMING THE RETIREMENT OF 500 MW IN JUNE

Since its *2005 Integrated Energy Policy Report (IEPR)*, the Energy Commission has urged the state's utilities to undertake long-term planning and procurement to allow for the orderly retirement or repowering by 2012 of aging power plants identified in the *2004 IEPR Update*.[23] In addition, Decision D.07-12-052 by the California Public Utilities Commission (CPUC) calls for a retiring generation from aging power plants in California, starting with 500 MW in the Los Angeles Basin in 2009.[24] The Decision neither specifies a generator or combination of generators, nor provides a specific time during the year when retirement(s) would occur.

Effecting the orderly retirement of aging plants has become more difficult as a result of a successful legal challenge to the South Coast Air Quality Management District's (SCAQMD) *Priority Reserve Rule* (Rule). The challenge was based on the on the argument that SCAQMD performed an inadequate California Environmental Quality Act (CEQA) analysis when adopting the Rule. As a result of the court's decision, SCAQMD is unable to issue any offsets for either power plants or any other facilities requiring a permit for emissions, thus delaying the replacement of aging generation in the Los Angeles Basin, as well as other air basins.[25]

Because retirement of aging plants as directed by the CPUC does not appear to be taking place prior to June 1, if at all during 2009, staff did not include a reduction of 500 MW in the SP 26 region in the *2009 Outlook*. However, staff examines the extent to which the retirement of 500 MWs in the SP 26 region during June would affect planning reserve margins in the SP 26, California ISO and Statewide regions.[26] NP 26 is not included separately because the assumed retirement would not have an effect there. However, the values for California ISO and Statewide have the NP 26 values imbedded in the estimates.

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[23] *Integrated Energy Policy Report, 2005* (November 2005), and *Integrated Energy Policy Report, 2004 Update* (November 2004).

[24] D.07-12-052, December 17, 2007. (http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/76979.htm accessed March 18, 2009.)

[25] Energy Commission staff examined the potential impacts of the *Priority Reserve* ruling. (Staff Draft Paper, *Potential Impacts of the South Coast Air Quality Management District Air Credit Limitations and Once-Through Cooling Mitigation on Southern California's Electricity System*, February 2008, CEC-200-2008-002-SD.)

[26] *ibid*. Tables 4 and 5 of the February 2009 Staff Draft Paper provide projections of planning reserve surpluses/deficits, and reserve margins for the years 2009 through 2013, inclusive. Assumed values for existing generation, generation additions, 1-in-2 demand, demand response, and interruptible/curtailable program values in the tables were based on now-stale information.

SP 26

Table C-1 shows that under 1-in-2 weather conditions, reserve margins in SP 26 do not fall below 20.2 percent (August), well above the upper-bound planning reserve margin target of 17 percent. Reserve margins drop to 11.3 percent in August and 13.7 percent in September under 1-in-10 weather conditions. The 11.3 percent value is close to the 11.8 percent during same month's 1-in-10 value in 2008, and as in 2008, there should be sufficient resources to cover a range of other system contingencies, such as unplanned facility outages.

California ISO

Under 1-in-2 weather conditions, reserve margins in the California ISO region never fall below 24.7 percent (August), and never less than 16.2 percent under 1-in-10 weather conditions (August).

Statewide

Under 1-in-2 weather conditions, reserve margins statewide never fall below 22.6 percent (August). Reserve margins do drop to 14.8 percent under 1-in-10 weather conditions (August), but when rounded-up equals the 15 percent standard.

Table C-1: Comparison of Reserve Margins Assuming an Unspecified Retirement of 500 MW in the Los Angeles Basin in June 2009

	Demand Forecast Weather Condition					
	1-in-2			1-in-10		
Region and Month	w/o 500 MW Retirement in LA Basin	w/ 500 MW Retirement in LA Basin	Diff	w/o 500 MW Retirement in LA Basin	w/ 500 MW Retirement in LA Basin	Diff
SP 26						
Jun	41.6%	39.5%	-2.0%	24.3%	22.5%	-1.8%
Jul	30.5%	28.6%	-1.9%	20.1%	18.4%	-1.7%
Aug	22.0%	20.2%	-1.8%	12.9%	11.3%	-1.6%
Sep	30.8%	28.9%	-1.9%	15.4%	13.7%	-1.7%
CA ISO						
Jun	36.3%	35.2%	-1.1%	22.0%	21.0%	-1.0%
Jul	26.0%	25.0%	-1.0%	18.5%	17.5%	-1.0%
Aug	25.8%	24.7%	-1.0%	17.1%	16.2%	-1.0%
Sep	33.8%	32.7%	-1.1%	19.8%	18.9%	-1.0%
Statewide						
Jun	35.4%	34.5%	-0.9%	21.7%	20.9%	-0.8%
Jul	24.1%	23.3%	-0.8%	16.1%	15.3%	-0.8%
Aug	23.4%	22.6%	-0.8%	15.6%	14.8%	-0.8%
Sep	31.3%	30.5%	-0.9%	18.2%	17.4%	-0.8%

Conclusions

Even when including the potential retirement of 500 MW of generation in SP 26, reserve margins are sufficient for the summer 2009 under 1-in-2 weather conditions. Although SP 26 planning reserve margins drop below the lower-limit of 15 percent under 1-in-10 weather conditions in August, the probability assessments indicate that resources likely are sufficient to cover a range of other system contingencies, such as unplanned facility outages are available.